STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

NORTH SHORE GAS COMPANY	)	
Proposed General Increase in	)	
Rates for Gas Service	)	
	)	**Docket No. 12-0511**
THE PEOPLES GAS LIGHT	)	**and 12-0512**
AND COKE COMPANY	)	**(Consolidated)**
Proposed General Increase in	)	
Rates for Gas Service	)	

DIRECT TESTIMONY OF MICHAEL L. BROSCH

ON BEHALF OF THE

PEOPLE OF THE STATE OF ILLINOIS

November 20, 2012

DIRECT TESTIMONY OF MICHAEL L. BROSCH

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I. INTRODUCTION / SUMMARY

Q. Please state your name and business address.

A. My name is Michael L. Brosch. My business address is PO Box 481934, Kansas City, Missouri 64148-1934.

Q. By whom are you employed and in what capacity?

A. I am a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to regulatory projects for utility regulation clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses, utility reorganization analyses and focused investigations related to utility operations and ratemaking issues.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the People of the State of Illinois represented by the Attorney General, ("Attorney General" or "AG").

Q. Will you summarize your educational background and professional experience in the field of utility regulation?

A. Yes. AG Exhibit No. 1.1 is a summary of my education and professional qualifications. I have testified before utility regulatory agencies in Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, New Mexico, Ohio, Oklahoma, Texas, Utah, Washington, and Wisconsin in regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and steam utilities. A listing of my previous testimonies in utility regulatory proceedings is set forth in AG Exhibit No. 1.2.

In Illinois, I have testified in several major proceedings before the Illinois Commerce Commission ("the Commission" or "the ICC"). These include Peoples Gas rate cases in Docket Nos. 90-0007 and 07-0241, North Shore Gas Company Docket No. 92-0242, Illinois Bell Telephone Company in Docket Nos. 92-0448 and 92-0239, ComEd rate case Docket Nos. 07-0566 and 10-0467 and Ameren Illinois Utilities Docket Nos. 07-0585 through 07-0590. I also testified in ComEd Docket No. 09-0263 involving the Advanced Metering Infrastructure Pilot Program and Associated Tariffs, in response to ComEd's alternative regulation proposal that was filed in Docket No. 10-0527. More recently I testified in the initial and second year formula rate case proceedings involving ComEd and Ameren Illinois, Docket Nos. 11-0721, 12-0321, 12-0001 and 12-0293, respectively.

Q. What is the purpose of your testimony in this docket?

A. My testimony is responsive to the asserted revenue requirement calculations and related testimony of North Shore Gas Company ("NSG") and The Peoples Gas Light and Coke Company ("PGL"), separately and collectively referred to as the ("Company" or "the Companies"). My testimony, and that of AG witness Mr. David Effron, supports a series of ratemaking adjustments to the Companies' filing that are summarized in AG Exhibits 1.3 and 1.4, for PGL and NSG, respectively. When all AG-proposed ratemaking adjustments and a recommended cost of capital are applied to the revenue requirement levels asserted by the Companies, a much lower overall revenue requirement is recommended by the Attorney General than has been proposed by PGL and NSG.

Q. What information have you relied upon in formulating your recommendations?

A. I have relied upon the Companies' pre-filed testimony and exhibits in these Dockets, as well as the Company's responses to data requests submitted by Staff, the AG and other parties. I also rely upon my prior experience with the regulation of public utilities over the past 34 years, including significant experience in Illinois.

Q. Have you prepared any accounting schedules to summarize the adjustments being proposed in your testimony and by Mr. Effron?

A. Yes. AG Exhibits 1.3 and 1.4 present calculations of the revenue requirement adjustments and results being proposed by Mr. Effron and me for PGL and NSG, respectively. The input value starting points for the revenue requirement calculations within AG Exhibits 1.3 and 1.4 are the Companies' Supplemental NS-PGL Ex. 18.1P and 18.1N for Operating Income, NS-PGL Ex. 19.1P and 19.1N for Rate Base and NS-PGL 17.1P and 17.1N for Cost of Capital. AG Exhibits 1.3 and 1.4 employ these starting amounts in Schedule B (Rate Base), Schedule C (Operating Income) and Schedule D (Cost of Capital), with AG-proposed adjustments separately set forth on Schedule labeled B-1, B-2, etc. and C-1, C-2, etc., for Rate Base and Operating Income, respectively. In addition to ratemaking adjustments to Rate Base and Operating Income, I have included proposed revisions to the cost of long term debt in Schedule D and have included the Return on Equity ("ROE") of 9.45% that was approved by the Commission for the Companies earlier this year.[1] The AG-proposed maximum revenue requirements is summarized on Schedule A, reflecting the posting of all of the AG-proposed adjustments at

[1] Docket Nos.11-0280/11-0281 cons., Final Order at page 145.

Schedule B, page 2 and Schedule C, pages 2 and 3, along with the revised Cost of Capital from Schedule D. Each of the revisions to the Company's Supplemental Testimony and Exhibits is described in more detail in my Direct Testimony and in Mr. Effron's Direct Testimony (AG Exhibit 2.0).

Q. Please summarize the recommendations that are set forth in your testimony.

A. The overall revenue increase for PGL and NSG *should not exceed* the amounts set forth in the following table:

TABLE 1: MAXIMUM INCREASE IN PRESENT BASE RATES (NON-GAS)

Base Revenue Increase $Millions	Peoples Gas	North Shore Gas
AG Proposed[2]	**$ 7.9**	**$ 0.3**
Company Proposed[3]	**$102.7**	**$12.5**
Difference	**$ 94.8**	**$12.2**

It should be noted that Mr. Effron and I have not, with available time and resources, been able to conduct a complete review of all aspects of the Company's filing. As a result, the limited adjustments we are proposing should be viewed as cumulative with the work and recommendations of Commission Staff and other parties' witnesses.

II. TEST YEAR CONSIDERATIONS.

[2] AG Proposed amounts reflect only ratemaking adjustments proposed by AG witnesses based upon limited review of the Companies' filings. The AG's final position on revenue requirement issues may include consideration of adjustments proposed by Staff or other parties' witnesses.

[3] Company proposed amounts reflect Supplemental Direct Testimony revisions.

Q. What is the purpose of a "test year" in the determination of public utility revenue requirements?

A. Energy utilities' rates have traditionally been regulated based upon their annual cost to provide service, including an opportunity to earn a reasonable return on invested capital. The process used to evaluate and measure the cost of service and resulting revenue requirement is the rate case, in which a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates can be undertaken at a common period in time, referred to as a "test year." The proper selection and consistent application of the test year is critically important, so that all of the components of the revenue requirement, including rate base, operating expenses, capital costs and sales or billing determinants are holistically analyzed and quantified in a balanced and internally consistent manner with appropriate "matching" of expenses, rate base, cost of capital and revenues.

Q. Are there several commonly employed types of rate case test years?

A. Yes. The two broad categories of test years include "historical" test years that employ actual, recorded financial information to develop the revenue requirement and "future" and "forecasted" test years that employ projections of expected future financial information to develop the revenue requirement. Within these two broad categories, the test year calculations can be based upon either an "average" set of rate base and operating income data throughout the 12 months of the year or, alternatively, an "end-of-period" or "annualized" approach that adjusts the various elements of the revenue requirement calculation to cost and revenue levels extant at year-end.

Q. What type of test year has been proposed by PGL and NSG in the determination of the asserted revenue requirement for each utility?

A. The Companies' proposed test year employs forecasted 2013 rate base, capital structure and operating income amounts. However, the Companies' filings are not internally consistent because they include both average and year-end information in a manner that distorts and overstates the asserted revenue requirement. The Company's proposed rate base is forecasted at year-end as of December 31, 2013, while the balance of the test year revenue requirement calculations, including revenues, O&M expenses and cost of debt, utilizes forecasted average data expected to be experienced throughout calendar year 2013.

Q. What issues are raised by the Companies' test year approach?

A. Whenever a forecasted test year is employed, the reasonableness of the utilities' forecasted revenue, expense, cost of capital and rate base data becomes critically important. Use of forecasted rather than actual recorded financial data creates an opportunity for management to aggressively forecast higher future costs because doing so is directly rewarded with higher utility rates and revenues. Future spending levels are inherently uncertain and judgment is required in preparing annual financial forecasts for any utility. The fiduciary obligation of utility management is to maximize returns for investors. This obligation requires that every foreseeable cost that <u>may</u> be incurred should be fully included in the ratemaking forecast to optimize the opportunity for future earnings, while any potential but uncertain opportunities to reduce future costs are easily ignored. In the Companies' rate case filings, it is apparent that PGL and NSG have aggressively forecasted higher test year 2013 costs by assuming:

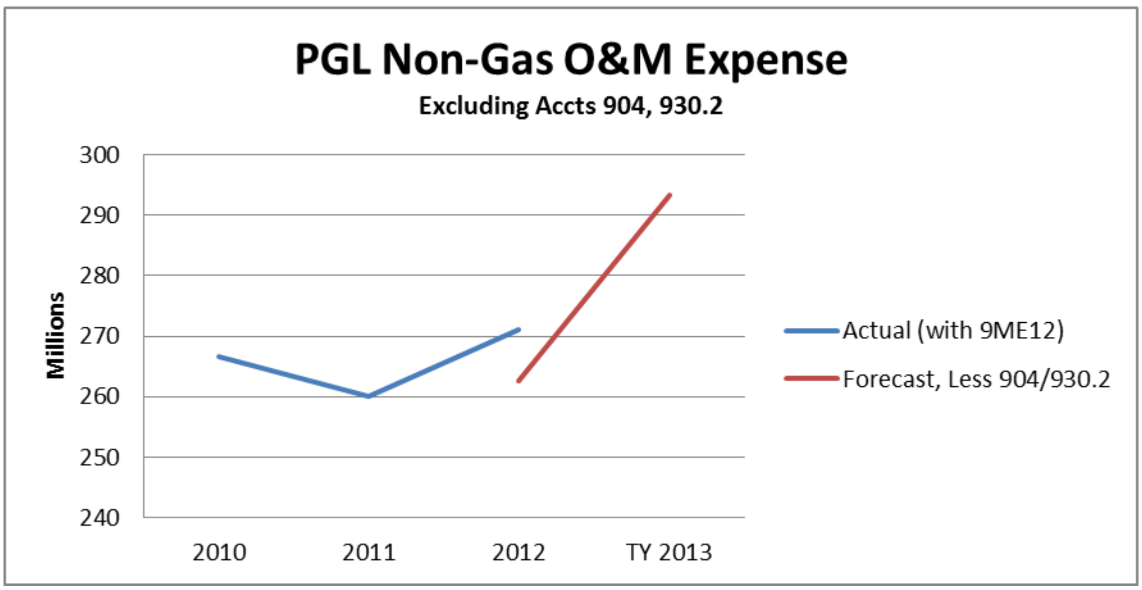
- Expanded workforce staffing levels with no vacant positions;
- Higher non-labor expenses than have been historically incurred;
- Rapid expansion of rate base investment;
- Unsupported estimates of much higher expenses for Chicago Department of Transportation ("CDOT") compliance and investigation/remediation of sewer line cross-bore problems;
- Overstated debt and equity cost rates; and
- Application of wage and inflation rate assumptions with no projection of productivity gains to offset higher future costs.

Several adjustments are proposed in my testimony to restate forecasted expenses in 2013 and to restate projected capital costs reflecting more reasonable estimates for the cost of long term debt as well as the return on equity ("ROE") rate that was recently approved for the Companies in the Commission Final Order in Docket Nos. 11-0280/11-0281 consolidated. Mr. Effron is proposing, in AG Exhibit 2.0, other adjustments to elements of the Companies' asserted rate base so as to include more credible estimated cost amounts for ratemaking purposes.

Q. How do the forecasted 2013 total O&M expense levels being proposed by PGL compare to recent actual expenses?

A. The most recent available recorded O&M expense data for PGL is for the nine months ended September 30, 2012. The following graph compares PGL recorded actual O&M expenses in 2010, 2011 and 2012 (nine months times 12/9 to annualize) to the comparable forecasted expenses in 2012 and test year 2013. From this comparison, the overstatement of test year expenses in the PGL filing becomes obvious. To aid in comparability between years, I have prepared this graph excluding Account 904 Uncollectible Accounts and Account 930.2 Miscellaneous General Expenses for all years, because certain expenses for PGL bad debts, energy efficiency programs and environmental remediation that are included in these accounts vary dramatically from year to year and are subject to special rate rider recovery from ratepayers:

<u>Table 2: PGL Forecasted Expense Comparison</u>

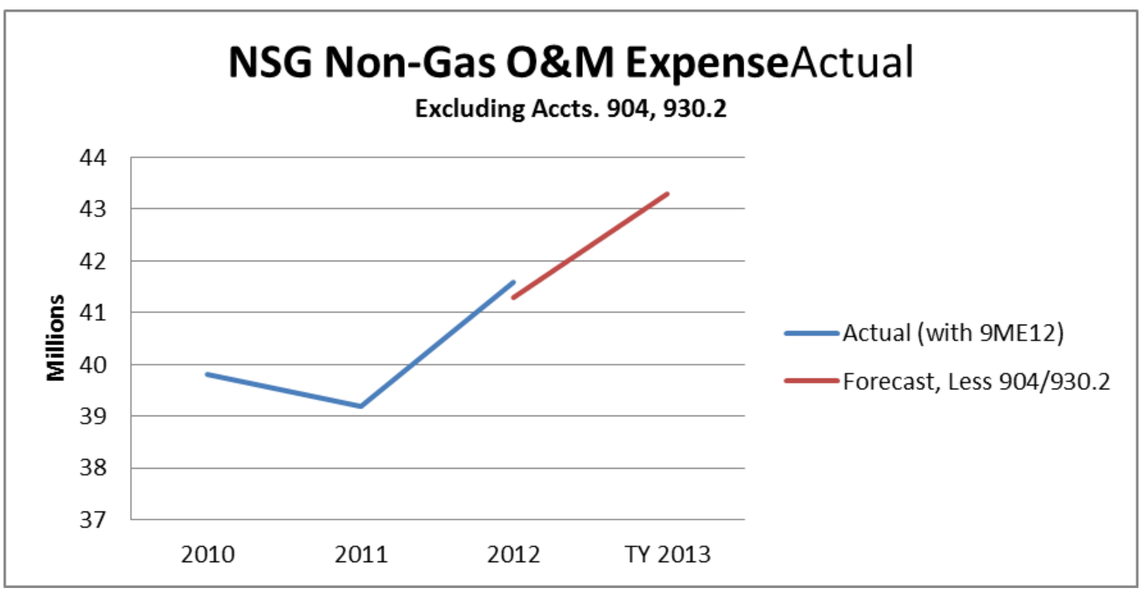


The amounts shown in this comparison are derived from PGL Schedule C-4, page 1 and from PGL's response to Data Request AG 6.06, Attachment 1 and compare the test year forecasted expense amounts to historical expenses before any ratemaking adjustments that may be applicable in each year. When the Company's proposed ratemaking adjustments are added to its forecasted 2013 O&M Expense, excluding gas costs, environmental remediation, energy efficiency and other rider-recovered expenses, the resulting adjusted expense level is $346 million, which is far above historical expense levels.[4]

Q. Does the test year forecast proposed for North Shore Gas also indicate apparent overstatement of O&M expenses when compared to recent recorded expense levels?

A. Yes, although the much higher projected 2013 expense levels in the NSG filing appear more credible only because North Shore's actual O&M levels in 2012 to date are dramatically higher than prior calendar years, when compared without Accounts 904 and 930.2:

<u>Table 3: NSG Forecasted Expense Comparisons.</u>



Some variation in recorded expense levels from year to year is quite normal. However, given the financial incentive for management to pessimistically forecast anticipated expenses in rate case test years, when comparisons to historical expense

[4] NS-PGL Ex. 18.1P, page 1, column E, line 24. This amount includes $18.3 million of adjusted Uncollectibles expense that is not included in the graph.

amounts show significantly higher projected ratemaking expense levels than have been incurred historically, careful analysis of the underlying support for the test year forecasting process and forecast results is essential.

Q. Beyond the overall amount of forecasted expense growth, does the Companies' filing raise another important issue with regard to test year cost forecasts?

A. Yes. The Companies have proposed the use of a hybrid test year approach, using forecasted operating revenues and operations and maintenance ("O&M") expenses throughout the 2013 test year that have <u>not</u> been annualized at year-end, while proposing a year-end rate base including net plant investment that is forecasted to exist at year-end. This approach significantly increases the test year 2013 revenue requirement, while destroying the balance that is normally required in test year regulation, where all elements of rate base and operating income are matched and made to be internally consistent. According to NSG/PGL witness Mr. Schott, "Peoples Gas' use of an end of year rate base calculation is appropriate and just. The revenue requirement is being determined based on a forecasted 2013 test year, but, the rates being set will not go into effect until well into the test year, *i.e.,* in July 2013. In addition, Peoples Gas is increasing the level of its investments to better serve customers."[5]

Q. Should the Commission approve the Companies' year-end rate base proposal?

A. No. I recommend that an average rate base be employed in setting the Companies' rates, so as to match the average income statement and cost of capital calculations that are employed while not overstating the revenue requirement expected to be

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5 PGL Ex. 1.0, page 3, lines 58-62. Essentially identical testimony appears in NSG Ex. 1.0, page 3 at line 47.

incurred in the 2013 test year. Mr. Effron has proposed adjustments in his testimony to adopt an average rate base calculation for the test year.[6]

Q. How do the Companies attempt to justify their proposed hybrid test year approach using year-end rate base in an otherwise average test year?

A. Mr. Hentgen argues for use of a year-end rate base at page 4 of his PGL and NSG testimonies.[7] He cites "several reasons" for this approach:

1. The rates being set in this proceeding will not go into effect until well into the test year, most likely not until sometime in July 2013 and will likely be in effect until sometime in 2015.
2. The Companies are permitted under the Commission's rules to use a year-end rate base.
3. The Companies have been and continue to increase their investment in plant in service to better serve their customers.

Aside from these arguments, the Companies' only quantitative analysis is offered in support of the third argument, where in PGL/NSG Exhibits 7.2, historical balances of "Gross and Net Plant" are summarized to show how such amounts have changed historically.

Q. Does an assumed effective date of new gas rates from these proceedings in mid-2013 support adoption of year-end rate base?

A. No. Between rate case orders, all the elements of the revenue requirement are subject to change and can be expected to change. It is impossible to accurately predict how the timing of new rates becoming effective will impact a utility's earnings. If future revenue or cost variances from the test year 2013 amounts that

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6 AG Ex. 2.0 at pages 5-8.

are used to set rates are favorable, the Company's earnings are likely to exceed authorized levels. Conversely, if such financial variances are negative, earned returns may be lower than authorized levels. When a future test year is employed to set rates, the potential for earnings attrition is minimized because the forecasted financial data upon which rates are based is not dated. Stated differently, there is minimal regulatory lag when a future/forecasted test year is employed. Under these circumstances, it is not reasonable to select only one element of the ratemaking equation, in this case the rate base amounts, and presume such amounts should be mismatched to the rest of the test year just in order to ensure that earnings are maximized.

Q. Have the Companies or Mr. Hentgen provided any quantification of either historical or projected earnings attrition to justify mismatching the forecasted test year by using average income statement and cost of capital amounts with year-end rate base?

A. No. In response to Data Requests DGK 7.06 and DGK 7.07, North Shore and PGL admitted that the only analysis performed in support of using the year-end versus average rate base position was presented in its direct filing in this case by Mr. Hentgen in comparing historical levels of Gross and Net Plant in Service.

Q. Do the historical trends in "Gross and Net Plant" quantified in PGL and NS Exhibits 7.2 reveal either historical earnings attrition or future expected earnings attrition that might justify using a year-end rate base?

A. No. The utilities' total revenue requirement is driven by more than just changes in Gross Plant in Service and Accumulated Depreciation. Operating income is a

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[7] PGL Ex. 7.0, page 4, lines 83-90; NG Ex. 7.0, page 4, lines 81-88.

function of sales and revenue levels and each category of labor and non-labor expense. Rate base investment levels are driven by changes in Net Plant in Service as well as changes in Accumulated Deferred Income Taxes ("ADIT"), gas in storage and other working capital elements. In the present economic environment, declining interest rates have created a setting in which long term debt can be refinanced to yield significant savings that reduce revenue requirements. Mr. Hentgen's single-issue analysis focused on historical changes in Gross and Net Plant in Service does not address the multitude of other issues that impact revenue requirements. It is therefore essential that a proper matching of the elements of the revenue requirement be maintained to ensure that just and reasonable rates are approved by the Commission.

Q. Are you responsible for development and presentation of the rate base to be used in calculating the initial formula rate case revenue requirement in this Docket?

A. No. AG witness Mr. Effron is addressing the rate base issues on behalf of the Attorney General, except for Cash Working Capital. He will respond to the Companies' year-end rate base proposal in greater detail and will sponsor the ratemaking adjustments to PGL and NSG rate base at AG Exhibits 1.3 and 1.4 Schedule B-1 that are appropriate.

III. FORECASTED LABOR EXPENSES

Q. How have PGL and NSG prepared their forecasts of test year labor expenses?

A. The test year labor forecast is the product of a projected employee staffing level times the wage rates expected to be in effect in the 2013 test year, with the resulting labor dollars spread among expense, capital and other FERC Accounts. A high level description of the O&M labor cost assumptions employed by each of the Companies is set forth at PGL/NSG Exhibit 5.1, page 8 (Schedule G-5).

Q. Are the forecasts of test year labor prepared separately for each business unit within the Companies?

A. Yes. The Companies' business is organized into budget groups referred to as "Home Centers". For each Home Center, the labor forecast starts with the loading of all actual employees and their current salary levels into the budgeting system. Working from this current labor cost input data, the Companies' budget preparers are then allowed to add or delete employees as necessary, enter estimated overtime percentages or dollars, estimate a rate for non-productive vacation and holiday time and then direct the splitting of resulting total labor costs for the Home Center among responsibility centers "receiving" labor services and the FERC account where costs should be recorded.[8] A similar process is employed by Integrys Business Support, LLC ("IBS") that provides centralized administrative and other services to PGL and NSG, as well as affiliates located in other states.[9]

Q. Are you proposing any adjustments to the Company's proposed level of test year labor expenses?

A. Yes. The Companies have admitted in response to data requests that the wage increase percentages used in the test year forecast are overstated. I am proposing an adjustment to reduce labor, benefits and payroll tax expenses for the corrected, lower *wage increase rates* that should be included in NSG and PGL forecasts. Second, I am proposing an adjustment to labor expenses, benefits and payroll taxes

[8] PGL and NSG response to Data Request AG 1.04.

for excessive *staffing levels* included in the test year forecast, as more fully described in the testimony that follows. Finally, I propose an overall reduction to projected O&M expenses to account for a conservatively estimated productivity offset to the growth rates assumed for the Companies' labor and non-labor expenses.

Q. How did PGL and NSG determine the number of employees to include in forecasted test year labor expenses in the test year?

A. As noted previously, the Companies started with actual staffing and salary/wage levels on the payroll when the forecast was prepared and then added personnel to the calculation of test year payroll where a need for expanded staffing was believed to exist. For North Shore, there are two home centers that had staffing increases compared to 2011 actual staffing levels. Four new employees were added to a new Home Center B45 Distribution Design within NSG where the same employees were previously on the IBS payroll and were charging their time and expense directly to NSG. The other NSG Home Center with staffing increases in the test year was B80 North Shore Operations where employees were added to treat as "filled" positions that were recently vacant. The requested headcount for NSG for the test year is 171 positions.[10]

With respect to PGL, June 2011 actual staffing consisted of 1,094 positions, but for the test year the Company has included 1,357 positions, attributing the addition of 263 employees to the Accelerated Main Replacement Program ("AMRP") and to a planned Reorganization within PGL.

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[9] PGL response to AG 3.14; NSG response to AG 3.06.
[10] NSG response to AG 3.03.

Q. Is PGL's proposed addition of 263 new employees to its 2011 workforce count of 1,094 employees unusual and potentially problematic when being proposed in a forecasted test year?

A. Yes. In my experience, it is highly unusual for a gas utility to expand staffing by 24 percent within only two years.[11] The potential for overstatement of test year labor expense is large when such a dramatic staffing increase coincides with a forecasted test year where projected higher expenses translate directly into higher gas rates and revenues. With this problem in mind, the AG asked repeatedly for all analyses of work requirements, labor demand or other documentation indicating a need for the proposed levels of increased staffing for each home center, along with explanations of how proposed staffing increases were determined and all information relied upon by management to determine the need for and prudence of expanded staffing. The PGL responses to these questions are included in AG Exhibit 1.5 and include only high level analysis and estimation of incremental labor demand.[12]

Q. In your opinion, has the Company failed to sufficiently justify the large increases in staffing that are proposed for PGL in the test year?

A. Yes. The Companies have submitted no Direct Testimony explaining or documenting the need for the vastly expanded staffing being proposed in the test

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[11] 263 added positions relative to 1,094 actual staffing in June 2011 is a 24% increase.

[12] PGL responses to AG 1.03 provided an Attachment 2 "high level overview for the increased administrative staffing for the 2012 PGL Gas Operations realignment", along with a statement that "PGL also increased field force staffing for AMRP in 2011 and 2012 and increased Inside Safety Inspection (ISI) staffing". AG 3.11 repeated the request for support analyses for the proposed increased staffing levels and the Company produced an Attachment that simply listed positions being added in each Home Center, attributing some to AMRP Impact and other positions to categories captioned "capital", "O&M" and "compliance for the reorganization." Again in AG 8.14, supporting analysis and documentation for proposed staffing increases was submitted and the response provided was in narrative form, with general references to "increased annual workload required to complete Inside Safety Inspections" and for AMRP staff increases "mostly related to adding field forces to complete more work" and "related to administrative functions."

year and, as demonstrated in AG Exhibit 1.5, very little documented support for 24 percent staffing growth has been produced in response to data requests.

Q. Is there another way to test the reasonableness of the Company's proposed test year staffing level?

A. Yes. Another test of the reasonableness of PGL's test year labor forecast is to evaluate whether the proposed level of staffing for the test year is being achieved in recent months of 2012. The premise here is that overstating a test year forecast of employee levels is not difficult, but it is unlikely that the utility would willingly hire and pay additional personnel between test years if the added positions were not truly needed. This is because new employee positions added between test years cannot be used directly to increase utility revenue requirements and rate levels like increased staffing forecasted within a rate case test year.

Q. What level of staffing has actually been achieved by PGL in 2012, compared to the proposed 1,357 test year positions?

A. The Company has significantly increased actual staffing levels above the 1,094 level as of June 2011, but is far below the 1,357 positions included in the test year forecasts. In the last four months of available data for the months of June, July, August and September of 2012, PGL staffing has plateaued at about 1,223 positions.[13] This represents the approximate midpoint between actual mid-2011 staffing levels and the staffing level included throughout the 2013 test year.

Q. Does PGL management control the timing of actual hiring actions that are required to fill new positions?

The Attachments to AG 8.14 provide only limited information to quantify how work is measured and correlated to the numbers of positions proposed to be added.

A. Yes. Utility management has considerable control over whether and when to take action to authorize, recruit, interview and hire for each new employee position. It is not unusual for a newly planned employee position to remain unfilled either due to difficulties in finding and hiring a candidate with appropriate skills or because of financial constraints that justify delayed hiring to meet earnings targets. It is also quite common for existing (rather than new) employee positions to be vacant from time to time after a resignation or retirement, when management may be either unwilling or unable to rapidly backfill the vacancy. There is a continuing process of "churn" in any typical utility's workforce, where some employees routinely retire, accept a new job elsewhere, are disabled or are fired or laid off by the employer. Turnover in workforce also creates unavoidable delays in the process of recruiting, interviewing and testing, making offers and actually hiring each new employee. This churn creates a continuing level of normal "vacancies" among approved staff positions that tends to cause actual staff levels to never achieve targeted full employment levels.

Q. Have the Companies acknowledged that a portion of approved employee positions are vacant in most months?

A. Yes. In its response to AG 7.29, PGL explained many of the vacant employee positions as of September 30, 2012 by referring to "pending hires", "offers have been made", "vacancies due to retirement" and "job transfers". In response to AG 6.10, the Attachment containing actual staffing statistics for IBS identified a number of references to retirements, vacancies, active recruiting and planning to hire activities. I have included in AG Exhibit 1.6 copies of the Companies responses to

[13] PGL response to AG 7.29, Attachment 1 shows Actual staffing of 1,222 in June, 1,226 in July,

AG 7.29, AG 6.10 and AG 7.11 containing staffing information for PGL, IBS and NSG, respectively.

Q. Have the utilities, in preparing their test year labor forecasts, assumed any vacancies will exist regarding the planned test year levels of employee staffing?

A. No. As noted in PGL Schedule G-5, "The number of employees is projected to remain constant in calendar year 2013 at 1,357." In NSG Schedule G-5, the Company states, "The number of employees is projected to remain constant at 171 in calendar year 2013." This is an unrealistic forecasting assumption because the achievement of full staffing, with no employee vacancies, is virtually impossible to maintain and is factually inconsistent with actual experienced levels of employee vacancies at these utilities.

Q. Please explain how the adjustment appearing at Schedule C-2 of AG Exhibit 1.3 (PGL) and Exhibit 1.4 (NSG) was prepared.

A. Schedule C-2 applies, at lines 11, an average vacancy factor for Company employees and IBS employees that is based upon actual versus authorized numbers of employees in each month of 2012. The "vacancy factor" is simply the number of authorized but unfilled employee positions in each month of 2012, from January through September, divided by the total number of authorized positions in each month. For example, if PGL had authorized 20 positions within a particular department in each month of 2012, but only had 19 of these positions filled with actual employees drawing pay and benefits, the vacancy factor would by five percent for that department (1 vacancy / 20 positions = 5 percent). These average vacancy factors for 2012, across all departments, are then applied to the annual

1,223 in August and 1,222 in September, for an average summer staffing level of 1,223.

labor expenses, employee benefit costs and payroll taxes either directly incurred by the utility or allocated to it from IBS, to yield adjustments that represent the estimated cost savings that would be achieved if:

1) the Commission fully accepted the Companies' proposed staffing levels for the test year in the absence of any quantitative justification for such staffing, and

2) Vacancies are assumed to exist at the higher proposed staffing levels targeted for 2013 in the same approximate levels as have been experienced in 2012 through September.

Q. Does your proposed vacancy adjustment accept the overall forecasted levels of staffing included in the Companies' test year expense forecasts?

A. Yes. The adjustments at Schedule C-2 accept and start with the premise that the Companies have reasonably forecasted targeted numbers of employees to run the business, but then impose an adjustment to recognize the reality that actual staffing levels do not achieve targeted staffing levels. In the event the Commission concludes that PGL, IBS or NSG have overstated the targeted levels of staffing that are included in test year forecasts, a further downward adjustment to labor and benefits costs would be appropriate to revise targeted staffing levels, along with the need to recognize ongoing vacancies.

Q. Did the Companies also include forecasted wage rate increases in development of the test year 2013 O&M expense amounts included within asserted revenue requirements?

A. Yes. Schedule G-5 in the Companies' filings reveals an assumed 3.8 percent wage rate increase for union employees in July of 2012 and again in July of 2013, which amounts represent a contractual increase of 3.25% in 2012 plus 0.55% for wage scale progressions and an expectation for the same union percentage increases in July 2013.[14] For non-union employees, Schedule G-5 reveals assumed base salary rate increases of 3.0 percent in both years, plus 0.4 percent for promotions and another 0.45 percent for discrete merit pay increases, for a total of 3.85% in both years.

Q. Have the Companies revised downward the wage rate increase assumptions that should be embedded in the test year forecast?

A. Yes. In response to data requests AG 7.12 and AG 7.30, the Companies indicated that the current union Labor Agreement actually expires at the end of April 2013 and wage increases thereafter are based upon the Companies' "Best Projection" which is now that a new Labor Agreement with the union in 2013 will include a negotiated general wage increase of 3.00 percent (rather than 3.25 percent originally included in the filing). A similar downward revision is now proposed for non-union salary rate increase assumption, as explained in response to data requests AG 7.13 and AG 7.31. According to these responses, the Companies intend to revise downward non-union salary increases for 2012 and 2013 to provide for a 2.6 percent general wage increase plus the same 0.4 percent allowance for promotions and 0.45 percent allowance for discrete merit increases for exemplary performance. I have included copies of these responses within AG Exhibit 1.7.

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[14] According to responses to AG 7.12c and AG 7.30g, "Although 0.55% was originally forecasted as the increase for progressions for Union wages as shown in Schedule G-5, page 8, the amounts subsequently was increased to 0.60%, which is the currently budgeted amount for the test year 2013 as reflected in WPG-1(1)p.11."

Q. Have the Companies provided calculations showing how their planned downward revisions to union and non-union wage increases would impact test year revenue requirements?

A. The Companies were asked to do so in data requests AG 10.12 and AG 10.25, for NSG and PGL respectively. The responses to these data requests contain attachments with detailed calculations of expense differences created by the revision of wage rate increase assumptions. Information from these responses was incorporated in my employee wage adjustments detailed in Schedule C-3 in both AG Exhibits 1.3 and 1.4, the revenue requirement computations for PGL and NSG, respectively.

IV. PRODUCTIVITY FORECAST ASSUMPTIONS.

Q. Have the Companies reduced their forecasted test year O&M to recognize any assumed gains in productivity?

A. No. The assumptions used by the Companies to forecast labor costs were described in the prior section of this testimony and involved projections of higher staffing levels escalated for anticipated future wage rate increases, with no offsetting adjustments for improved productivity. With regard to non-labor "Other Costs" that are included in O&M, the Companies' Schedule G-5 states, "The Company forecasted operating and maintenance costs through a bottoms-up budgeting process. Unless specifically determined otherwise, this process assumed, as a default, a 2.1% and 2.2% annual rate of inflation for 2012 and 2013 respectively.

The Cost of natural gas purchased for the Company's internal use was forecasted in a similar manner as natural gas purchased for sales to customers."

Utilization of the same general inflation escalation approach to non-labor expenses is confirmed in the Companies responses to data requests AG 3.07 and 3.15 which state, "Generally, other costs forecasted for the test year are updated by the inflation rate given in the assumptions unless specific increases/decreases are known" and then provide a series of non-labor forecast worksheets which broadly employ general inflation-based escalation rates.

Q. What is "productivity" and why is it relevant to the development of utility revenue requirements when such amounts are based upon a forecasted test year?

A. Productivity is a measure of the efficiency of production, based upon the ratio of production output relative to the input resources that are required to produce output, such as labor, materials and contractor services. For a utility or any other business enterprise, productivity gains represent the ability to do more work with fewer hours of labor and/or reduced materials and contractor input resources. Productivity gains can be achieved through implementation of improved methods of operation, automation of work processes, increased use of technology, employee training and diligent management oversight and control of costs.

Q. Should utilities like PGL and NSG be expected to continuously improve their operations to seek and achieve productivity gains in their operations?

A. Yes. Productivity improvement is an essential responsibility of utility management, just as it is for non-regulated businesses in competitive markets. Continuously improved productivity is reasonably expected by ratepayers who are ultimately responsible for costs incurred on their behalf. It is reasonable to expect that any forecasted test year make some accounting for productivity changes as an offset to estimated cost increases for inflation and employee wage rates.

Q. Are you aware of other regulatory commissions that require an accounting for productivity changes in setting utility rates?

A. Yes. For example, the California Public Utilities Commission ("CPUC") sets rates for energy utilities for multiple years using forecasted financial information and inflations indices, but then requires an offset for expected productivity improvements within the forecast period. In a recent San Diego Gas & Electric Company ("SDG&E") rate proceeding, a witness for SDG&E testified that, "The average trend in the productivity of all sampled gas distributors was found to be 1.18% growth per annum over the full 1999-2008 period and .99% per annum over the five most recent years."[15]

In New York Public Service Commission Case 09-E-0588, the *Order Establishing Rate Plan* issued June 18, 2010, approved a settlement agreement involving Central Hudson Gas and Electric stating:

> Consistent with the Commission's Policy, as articulated most recently in its Order Approving Ratepayer Credits (issued and effective December 22, 2009) in Case 09-M-0435, the revenue requirements and Income Statements shown in Appendix A incorporate the following adjustments to the Company's gas and electric expenses: an additional 1/2% productivity for a total of 1 1/2% in each Rate Year, establishment of zero current rate allowances for the costs of the Supplemental Executive Retirement Program, and the deferral of costs of planning for and implementing International Financial Reporting Standards ("IFRS") in Rate Years 2 and 3. Additional austerity includes

[15] There were 34 sampled utilities in this study, included North Shore Gas and Peoples Gas. See prepared Direct Testimony of Mark Lowry filed December 2010 in Application 10-12-__, available at: http://www.sdge.com/sites/default/files/regulatory/Exh%20SDG%26E-44%20M_Lowry_Productivity.PDF

> the July-December portion of the Company's prior commitment to freeze executive salaries for 2010.[16]

Q. In prior testimony, you noted the absence of any productivity offset within the Company's test year expense forecast. Have the Companies conducted any studies or have any reports that analyze trends in their productivity?

A. According to the Companies' responses to data requests AG 7.6, AG 7.7, AG 7.24 and AG 7.25, the Companies "do not have any studies, reports, analyses, projections or other information, prepared since January 1, 2010, that quantifies changes in productivity" and PGL and NSG, "do not document changes in the level of productivity." I have included copies of these responses within AG Exhibit 1.8.

Q. What adjustment do you recommend be applied to the Companies estimated test year O&M expenses in the absence of any systematic measurement or informed estimate of productivity gains that may be achievable in 2012 and 2013 to offset assumed inflation and higher projected employee wage rates?

A. I propose utilization of at least a one half of one percent per year productivity adjustment that reduces PGL and NSG asserted test year non-fuel O&M expenses that are not tracked through any rate adjustment riders. Since the Companies' rate case forecast is based upon projected costs in 2012 and 2013, the cumulative adjustment would be for two years for a cumulative O&M reduction of one percent. This subjective adjustment is based upon an expectation that management should be able to achieve this modest level of annual productivity improvement in its operations. I recommend that the Commission assume and account for productivity gains at this level in the absence of any study, quantification, evidence or

[16] Order Establishing Rate Plan, June 18, 2010, Central Hudson Gas & Electric Corporation Case

adjustment by the Companies to consider how productivity improvements will offset the impacts of inflation and higher wage rates that have been fully reflected in test year expense forecasts in the Companies' filing.

Q. Does any portion of the Companies' rate case testimony indicate that management expects to actually achieve productivity gains that will serve to reduce O&M expenses?

A. Yes. Companies' witness Ms. Cleary notes in her testimony that the Commission disallowed a portion of costs associated with the Integrys Non-Executive Incentive Plan in ICC Docket Nos. 11-0280/11-0281 Cons., where such incentives were tied to the *Cost Management Non-fuel O&M Expense* metric within that Plan. Ms. Cleary, in seeking full recovery of the same costs in the instant rate cases, opines that, "This metric encourages employees to maintain or reduce operational costs in order to keep O&M costs at or below the target level set for Peoples Gas. The more O&M costs are reduced, the higher the payout for which employees may be eligible. This metric benefits customers because all else being equal, lowering O&M expenses will reduce the amount of costs to be recovered in future rate cases." In my view, if there are no productivity gains being achieved and expressly considered in the development of test year forecasts, ratepayers cannot reasonably be made responsible for incentive compensation tied to such gains. In the next section of this testimony I address ratemaking treatment of the Companies' asserted incentive compensation expenses.

09-E-0588, 0589, page 6. Available at: http://www.cenhud.com/pdf/2010_rateplan.pdf

V. INCENTIVE COMPENSATION

Q. What amounts of Incentive Compensation costs are included in the Companies' asserted revenue requirements?

A. Test year incentive compensation expenses total about $11.5 million for PGL and about $1.8 million for NSG in the projected test year. These expense amounts relate primarily to the estimated awards under the 2013 Annual Incentive Plan, with smaller amounts attributable to estimated expenses for Stock Options, Performance Shares and Restricted Stock. Additional incentive plan cost amounts are proposed for rate base inclusion when such labor-related amounts are capitalized in support of plant construction activities. The estimated 2013 amount of incentives charged to construction is $1.2 million for PGL and $0.1 million for NSG.[17]

Q. What are the terms associated with the 2013 Annual Incentive Plan?

A. The incentive compensation amounts forecasted by the Companies in the test year have been developed based upon the terms of the incentive compensation plans in effect for performance during the calendar year 2012, in light of the fact that while the North Shore Gas and Peoples Gas incentive compensation plans for performance occurring during the calendar year 2013 will not be approved until early 2013, those plans are expected to be substantially identical with the same metrics and weightings as the 2012 plan that is set forth in PGL NSG Exhibit 9.1, sponsored by Ms. Cleary.

[17] PGL and NSG responses to data requests JMO 15.01 Attachment 1 and JMO 15.02 Attachment 1.

Q. Have the utilities provided any supporting documentation to explain any of the stock option, restricted stock or performance shares incentive compensation arrangements?

A. No. Only the Annual Incentive Plan that is formally named "Integrys 2012 IBS & Regulated Non-Executive Incentive Plan" has been documented in the Company's testimony.[18] Ms. Cleary's testimony makes no mention of the other stock-based incentive compensation plans.

Q. What are the primary drivers of incentive payouts under the Non-executive Annual Incentive Plan that is described in the NSG/PGL Exhibit 9.1?

A. As more fully explained in Exhibit 9.1, performance is weighted among several categories that vary slightly for persons directly employed by PGL or NSG, persons employed by IBS, and employees of other Integrys business units. For PGL and NSG, the targeted performance areas are:

- Adjusted O&M Expenses (combined all utilities) 50%
- Employee Safety (OSHA accident rates) 15%
- Customer Satisfaction Surveys (by utility) 15%
- Leak Reduction (PGL class II / NSG total leaks) 10%
- Reduction in Damages by Company Crews 5%
- Reduction in Damages by 2nd,3rd Party Crews 5%

The Annual Incentive plan is based upon targeted performance levels in each area, with actual performance measured and compared to targets after each calendar year-end, to calculate cash incentive amounts payable to employees in March.

[18] See NSG/PGL Exhibit 9.1.

Q. Will PGL and NSG employees earn incentive compensation under the Adjusted O&M Expenses metric if the Company actually spends the amounts that are projected in the test year for non-fuel Adjusted O&M expense?

A. This cannot be determined, because the performance parameters for the actual 2013 Annual Incentive plan have not yet been developed and approved.[19]

Q. If the Annual Incentive plan is effective at promoting and achieving reductions in test year expenses so that such expenses are ultimately lower than the forecasted amounts being used to establish revenue requirements, should ratepayers be responsible for the expenses for the incentive plan?

A. No. Any achieved future O&M savings, relative to asserted test year levels of expenses, will be retained for the sole benefit of shareholders because test year expense amounts for ratemaking purposes are based upon forecasted expense amounts rather than upon actual expense levels that drive incentive plan payouts. The Companies have not identified any reductions included in their test year O&M estimates that represent specific cost savings or assumed productivity offsets to forecasted inflation and wage rate escalations that will result from incentives being paid to employees. Absent a calibration of specific O&M reductions to the incentive compensation metrics in the Company's test year expense forecasts, the Commission should assume that the Annual Incentive plan O&M component is self-funded out of expense savings that are being retained for the sole benefit of shareholders. The alternative assumption would be that expense savings are not being achieved at levels sufficient to "pay for" annual incentives to employees, in

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19 Companies' response to data requests AG 7.18 and AG 7.36 for NSG and PGL, respectively.

which instance the O&M components of the Annual Incentive plan is dysfunctional and should be discontinued by the Companies.

Q. How does the Company explain the linkage between achieved O&M savings and rate recovery of incentive compensation that is driven by O&M performance?

A. The Companies' response to AG 7.36 states:

> As detailed in PGL Ex. 9.0 and NS Ex. 9.0, pages 9-10, North Shore Gas and Peoples Gas experienced significant reduction and control of their overall Total Nonfuel O&M Expense Adjusted in 2011 after the O&M cost-control metric was included in the Non-Executive Incentive Plan governing performance for that year. The same metric was included in the Non-Executive Incentive Plan governing performance for 2012, although data is not yet available to show how the Companies performed in terms of their Total Non-fuel O&M Expense Adjusted in 2012, and it is expected that the Non-Executive Incentive Plan governing performance for 2013 will also include the same metric. It is commonly understood that when costs are reduced or controlled in one year, that reduction or control carries through to the basis used in planning the following years' budgets. Accordingly, with respect to the amount of O&M costs budgeted since the adoption of this incentive performance metric in 2011, it is believed that amount of Total Nonfuel O&M Expense Adjusted included in the revenue requirements related to those budgets likely would have been higher in the absence of the Integrys Non-Executive Incentive Plan's cost control metric having been in place. It is not possible, however, to show a direct link to particular dollars in specific line items of the annual O&M budgets that have been reduced or controlled (i.e., would otherwise have been larger) as a result of the O&M cost control metric. Peoples Gas and North Shore Gas are not aware of a method by which such impact can be accounted for and quantified in such a manner. Based upon numerous past orders of the Commission that have allowed recovery of incentive costs for metrics that reduce or control operational costs, however, Peoples Gas and North Shore Gas have included this metric in their Non-Executive Incentive Plans to incentivize employees to work towards the reduction and control of O&M costs, which, everything else being equal, will result in benefits to customers in the form of lower rates than they would otherwise experience.

I reject the stated assumption in this response that, "It is commonly understood that when costs are reduced or controlled in one year, that reduction or control carries through to the basis used in planning the following years' budgets." The much higher O&M expenses being proposed by the Companies in the test year in these dockets reflect no apparent cost controls either historically or assumed to be exercised in the future. I submit that the absence of any direct link between forecasted test year adjusted O&M and the targeted O&M within incentive compensation plans is a flaw that should preclude rate recovery of such incentive compensation amounts.

Q. Will there ever be an observable direct link between forecasted PGL and NSG test year adjusted O&M expenses and the amounts that drive payouts under the Companies' Annual Incentive plan?

A. No. The targeted O&M expenses used to administer the Annual Incentive plan are set forth in Appendix A in PGL/NSG Exhibit 9.1 and is a combined "Utility and IBS FERC-based non-fuel O&M" amount from the consolidated budgets of *all* Integrys utility subsidiaries, along with IBS expenses. This large pool of O&M that drives incentive payouts is influenced by O&M performance of multiple Integrys businesses beyond PGL and NSG. Not only is the O&M parameter of the Annual Incentive plan not tied to expenses included in 2013 rate case forecasted O&M, the payouts under this plan are ultimately driven by a much larger universe of utility operations than just these two Illinois utilities. As such, the Companies have failed to demonstrate any kind of identifiable PGL/NS customer benefit associated with the O&M expense element of the Annual Incentive plan.

Q. What adjustment do you propose with respect to test year incentive compensation costs that are forecasted by PGL and NSG?

A. AG Exhibit 1.3 and Exhibit 1.4 at Schedule C-5 contain calculations showing the disallowance of 50 percent of the Annual Incentive Plan expenses that have been included in the Companies test year O&M expense forecast. The remainder of the Annual Incentive plan expenses driven by employee safety, customer satisfaction and leak response is allowed to remain in test year projected expenses based upon an assumption that these plan parameters are cost effective, provide a direct customer benefit and will be met in the test year.

Column D reflects the AG's proposed disallowance of 100 percent of the test year expenses for each of the stock-based compensation plans in the test year.

Q. Have the Companies conceded rate recovery of the stock-based incentive compensation plans?

A. Yes. In response to data requests AG 8.17 and CUB 2.02, the Companies acknowledged the Commission's rulings regarding these stock-based incentive plans and stated, "…without any waiver of their right to assert these arguments in future rate cases or other proceedings, Peoples Gas and North Shore will not contest any disallowance proposed for these particular incentive compensation costs made in this rate case in order to narrow the issues to be decided by the Commission."

Q. Earlier in this testimony, you proposed a productivity adjustment reducing non-fuel O&M expenses in the Companies' test year forecast by at least one half of one percent per year. Should your productivity adjustment be imposed at the same time the Companies' Annual Incentive Plan O&M-related costs

are disallowed, since that plan may help PGL and NSG actually achieve such productivity gains?

A. Yes. The large amounts of Annual Incentive Compensation that are included in the Companies' asserted revenue requirement imply a need for much larger productivity gains than the minimum one-half percent per year allowance recommended in my testimony. For example, the 50 percent of Annual Incentive costs estimated for PGL that are driven by O&M cost savings achievement would add more than $5 million to annual expenses ($10.2 million in total expense times 50 percent).[20] Assuming that the incentive paid should represent only a reasonable fraction, perhaps no more than half of the actual O&M savings experienced by the Company, expense savings of $10 million or more should be expected in each year that PGL pays out such large incentives. Annual savings of $10 million would represent nearly three percent of PGL's proposed Total O&M Expenses of $346 million[21] in the test year. This comparison implies that my one-half percent annual assumed productivity reduction to O&M is conservative in light of, (1) the annual achievable savings that the Companies themselves believe are within management control, and (2) the fact that the Companies should be able to "pay for" the O&M element of Annual Incentive Plan costs out of retained O&M savings that are not being fully reflected in test year expense estimates.

VI. STATE INCOME TAX RATE ISSUE

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[20] PGL response to data request JMO 15.01, Attachment 1 indicates test year Annual Incentive Plan expenses of $10,207,920 are included in test year forecasted expenses.

[21] See NS-PGL Ex. 18.1P , page 1 of 1, column E, line 24.

Q. Have PGL and NSG recognized the higher Illinois corporate income tax rate that became effective in 2011?

A. Yes. PGL and NSG Exhibits 5.1, at Schedule C-5, reflects utilization of the higher 9.5% Illinois State Tax Rate at line 18, to calculate a "Total State Taxes" amount at line 19. Schedule C-5 also shows at line 26 that "Current State Income Taxes" are negative, indicating that at present rate levels the Company would not pay any State income taxes. PGL and NSG instead are recording substantial positive Deferred Income Tax expenses, as shown at line 6 of Schedule C-5. Unfortunately, the Company's calculations assume that PGL and NSG will experience taxable income and actually pay taxes at the currently higher State income tax rates, even though the Companies' current state income tax obligations are mostly deferred into future tax years.

Q. Are Illinois State Income Tax rates scheduled to remain at the higher 9.5% corporate income tax rate in all future years?

A. No. The Illinois corporate income tax rate is scheduled to drop back to 7.75% in 2015 and then drop back to the original 7.3% rate in 2025.[22]

Q. Will the scheduled reduction in future Illinois State Income Tax rates result in some income tax savings to PGL and NSG?

A. Yes. The Companies' income tax deductions taken today will produce income tax deferrals today when tax rates are at the higher 9.5% rate, creating book/tax timing differences and deferred income taxes that will reverse in future years, at which time income taxes will become payable at the lower tax rates scheduled to be

[22] 35 ILCS 5/Art. 2. Available at: http://www.ilga.gov/legislation/ilcs/ilcs4.asp?DocName=003500050HArt%2E+2&ActID=577&ChapterID=8&SeqStart=600000&SeqEnd=3100000

effective at that time. This phenomenon is completely ignored in the Companies' filing, but was the subject of specific large ratemaking adjustments in ComEd's formula rate update filing in Docket No. 12-0321 and in Ameren Illinois Companies' formula rate update filing in Docket No. 12-0293.

Q. How did ComEd explain the ratemaking implications of the temporary increase in corporate state income tax rates?

A. In the ComEd filing in Docket No. 12-0321, Company witness Mr. Fruehe testified as follows:

> Q. **How did the increase in the Illinois income tax rate in 2011 impact the revenue requirement?**
>
> A. The passage of Illinois Senate Bill 2505 on January 13, 2011 increased the previous corporate income tax rate of 7.3% to 9.50% for the years 2011 through 2014, with reductions to 7.75% in 2015 and 7.3% in 2025. This change impacts the revenue requirement in several ways.
>
> First, the statutory state income tax rate used to calculate the overall total income tax rate on Schedule FR C-4 has been revised to reflect the 9.5% statutory state income tax rate.
>
> Second, as a result of the change in the rate, previously recorded accumulated deferred income tax balances, i.e. balances as of December 31, 2010, were required to be remeasured to reflect the deferred tax balances calculated by applying the new tax rates noted above. The remeasurement of ADIT resulted in a required increase to jurisdictional ADIT as of January 1, 2011 of $13.1 million. Consistent with prior ICC guidance (ICC Docket No. 83-0309, addressing the manner in which deferred tax impacts resulting from tax rate changes should be addressed), this shortfall in ADIT is offset by a regulatory asset and is being amortized prospectively over the remaining life of the underlying assets by applying a weighted-average rate method for future reversals.

> Amortization of the remeasurement balance was a credit of $1.9 million in 2011.
>
> Finally, in 2011, ComEd recognized a significant benefit due to the difference between the current income tax rate of 9.50% and the rate at which the related deferred tax expense is recorded. The deferred tax rate is lower because, as described above, the state income tax rate is scheduled to decline in 2015 and again in 2025, which means that some of the deferred taxes recorded in 2011 will reverse in later years when the state income tax rate is scheduled to be lower. This difference in current and deferred tax rates, combined with the fact that during 2011 ComEd had two notable and significant tax deductions (100% bonus depreciation and the expense related to the adoption of the T&D repairs safe harbor methodology) resulted in a 2011 tax benefit of $16,960,000 (jurisdictional), which is included in the tax adjustments shown on Schedule FR C-4.

Q. Were the income tax expense adjustments that were recognized in formula rates by ComEd due to lower future stated income tax individually significant?

A. Yes. The third adjustment described in the paragraph of Mr. Fruehe's testimony that begins with the word "Finally" is quite significant, resulting in a 2011 income tax expense benefit of $16.9 million. This adjustment is quantified at ComEd Ex. 3.2, WP 9, page 2 of 4 and results from utilization of lower income tax rates to calculate deferred income tax expenses in 2011, in anticipation of reversal of book/tax timing differences in future years when state income tax rates are scheduled to be lower.

Q. How was this issue of temporarily lower State income tax rates addressed in the Ameren formula rate proceeding?

A. Ameren initially ignored the deferred tax savings caused by lower schedule future State income tax rates in its Direct Testimony filing in Docket No. 12-0293, but when challenged by the AG and other parties regarding omission of these tax savings, the Company came forward with an accounting for the income tax benefits in its Rebuttal filing. Ameren did not dispute that the deferred income tax savings from the scheduled reduction in State income tax rates were real and would materially affect its formula revenue requirement. Instead, the Company argued that amortization of the tax savings was required under Section 16-108.5(c)(4)(F) of the formula ratemaking law. A proposed order has been issued in Docket No. 12-0293 that requires recognition of the deferred income tax savings associated with lower future State income tax rates, stating:

> The Commission has reviewed the parties' arguments and understands that the only material dispute is how to reflect the tax savings amount for ratemaking purposes. The parties' positions focus in large part on the application of Section 16-108.5(c)(4)(F) of the Act. The Commission has considered this issue and concludes that Staff, CUB, and AG/AARP have properly applied the law for the reasons they offer. The Commission notes, however, that Staff and AG/AARP have calculated the revenue impact of the adjustment differently. Upon reviewing the calculations by each party, Mr. Brosch appears to have neglected to apply the gross revenue conversion factor.[23] Staff's calculation, on the other hand, properly incorporates the gross revenue conversion factor. For this reason, Staff's calculations are adopted.[24]

Q. Do the State Income Tax rates and Generally Accepted Accounting Principles that apply to ComEd and Ameren apply equally to PGL and NSG?

A. Yes. While the specific tax deductions and income levels are obviously unique to each of the two utilities, there is no reason why ComEd and Ameren would be the only utilities able to benefit from the expected turnaround of tax deferrals in future years when State income tax rates are scheduled to be lower. PGL and NSG offer no testimony or calculations indicating how the changing Illinois state income tax rates will impact its ADIT accounting or recorded deferred income tax expenses.

Q. How do the Companies explain the absence of deferred income tax expense adjustments comparable to those included in ComEd's and Ameren's formula rate proceedings?

A. In its responses to data requests AG 7.03c and 7.21c, the Companies claim to be using an Average Rate Assumption Method ("ARAM") to account for the effect of changing tax rates in calculating deferred income tax provisions and reversals. The Companies cite to the Commission's Order in Docket No. 83-0309 that is believed to apply directly to the temporary increase in State income tax rates in the 2013 test year. In part (a) of these responses, the Companies also assert that the ARAM accounting procedures were employed in the last rate cases in Illinois, Docket Nos. 11-0280/0281 cons., but the cited provisions of the Commission's Order indicate that there was no issue raised regarding the alternative approach being followed by ComEd and Ameren using the Liability Method of deferred income tax accounting that is prescribed by Generally Accepted Accounting Principles ("GAAP"). The Final Order issued on January 10, 2012, in the prior PGL/NSG rate cases, does not list income tax expense among the contested issues and the only ADIT dispute involved accounting for uncertain tax positions using a 50/50 sharing approach. I

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[23] As will be noted in the AG/AARP Brief on Exceptions, to be filed on November 21, 2012, Mr. Brosch in fact did apply the gross revenue conversion factor, as demonstrated in Revised and Corrected AG/AARP Ex. 3.1, page 1.

[24] Docket No. 12-0293, Proposed Order, November 7, 2012 at 95.

have included copies of the Companies responses to data requests AG 7.03 and 7.21 within AG Exhibit 1.9.

Q. What is the ARAM method of deferred income tax accounting?

A. The Average Rate Assumption Method is required under Federal Internal Revenue Code Provisions to prevent the rapid flow through of accelerated tax depreciation benefits to ratepayers under the Tax Reform Act of 1986 ("TRA86"). TRA 86' reduced the maximum federal income tax rate for corporations from 46% to 34%. This reduction in the federal tax rate not only reduces tax payments currently being made, but also reduces future tax payments that would be owed when previously recorded deferred tax amounts are reversed, given rise to a so-called excess in the recorded reserve for deferred taxes. The ARAM method generally requires the development of an average rate determined by dividing the aggregate normalized timing differences into the accumulated deferred taxes that have been provided on those timing differences. As the timing differences begin to reverse, the turnaround is recorded at this average rate. Under this method, the co-called excess in the reserve for deferred taxes is reduced over the remaining life of the related property.

Q. Does the ARAM restriction apply to only Federal Income taxes and not the accounting for State income taxes?

A. Yes. IRC Section 168(e) sets forth "Normalization Requirements" that must be satisfied for a taxpayer to continue to qualify for accelerated methods of tax depreciation and if such requirements are not satisfied, the taxpayer is limited to deduction of only straight-line depreciation on its federal income tax return. These limitations have no applicability to the Companies' accounting for State income taxes. ARAM accounting was implemented in 1986 as part of the TRA 86 federal income tax transition rules to protect utilities from the rapid flow-back by regulators of the then-excessive recorded federal ADIT balances when Federal tax rates were reduced from 46 percent to 35 percent.

Q. You mentioned previously that ComEd and Ameren have adopted an accounting method for State Deferred Income taxes that recognized *currently* the lower State income tax rates that are expected to be effective when deferred taxes being recorded today are ultimately reversed in future years. What accounting method are they using?

A. A liability method of accounting for Deferred Income Taxes is required under Accounting Standards Codification 840 ("ASC 840"). These requirements were previously referred to as Financial Accounting Standard 109 ("FAS 109") and require for financial reporting purposes that deferred taxes be provided in an amount sufficient to represent the estimated liability that will be paid when book/tax timing differences reverse in future period. The liability method of deferred tax accounting applies to ComEd, Ameren and equally to PGL and NSG.

Q. Do PGL and NSG agree that they must comply with ASC 840/FAS 109 accounting requirements?

A. Yes. However, the Companies apparently believe their method of accounting for deferred income taxes for regulatory purposes is or should be different and more restrictive than what is required for financial reporting purposes. The Companies assert that ARAM is required for them by virtue of a Commission Order issued in ICC Docket No. 83-0309 and that, "To use the liability method required by FAS

109 for income statement and cost of service would be a direct violation of federal income tax normalization rules."[25]

Q. Does the Commission's Order in Docket No. 83-0309 have any applicability to temporary changes in state income tax rates?

A. No. Docket No. 83-0309 was an investigation into appropriate ratemaking and accounting for the excess deferred income taxes resulting from TRA 86 reductions in the Federal income tax rates from 46% to 35% more than 20 years ago. The Ordering paragraph in that Docket required "that utilities subject to the Commission's jurisdiction over rates which utilize deferred tax accounting shall for ratemaking purposes account for *reversals* resulting from changes in federal and Illinois corporate income tax rates for income taxes deferred in prior years at the weighted average rates at which such deferred income taxes were originally recorded…".[emphasis added] A full copy of this decision is included as Attachment 2 to North Shore's response to AG 7.03 within AG Exhibit 1.9. The issue presently before the Commission that was resolved for ComEd and Ameren in the earlier formula rate proceedings has nothing to do with excess deferred income taxes and has nothing to do with reversals of previously recorded ADIT balances. PGL and NSG are able, and should be required, to practice the same liability method of accounting that is employed by ComEd and Ameren for deferred tax provisions based upon the state income tax rates that will be effective in future years when such provisions will reverse.

Q. Does use of the liability method of accounting for State deferred taxes violate any federal income tax normalization rules?

[25] PGL/NSG responses to data requests AG 7.03e and 7.21e.

A. No. The federal income tax normalization rules apply to regulatory treatment of federal income tax benefits and provide for the loss of federal tax deductions and credits only when improper flow-through of federal tax deductions has occurred.

Q. What adjustment is required to apply the same liability method of deferred income tax accounting to PGL and NSG that has been employed by ComEd and Ameren for ratemaking purposes?

A. AG Exhibits 1.3 and 1.4 contain, at Schedule C-10, adjustments to deferred income tax expense to reflect the liability method of accounting rather than the ARAM approach advocated by the Companies. The adjustment amounts I have posted were estimated by PGL and NSG in their responses to data requests AG 7.02(f) and 7.20(f), respectively. I have included copies of these responses in AG Exhibit 1.10, excluding the voluminous attachments.

VII. INVESTED CAPITAL TAX

Q. Have the Companies included Invested Capital tax expenses in their forecasted revenue requirements that are reasonable in amount?

A. No. The invested capital tax is formula-driven, applying a 0.8 percent tax rate to the simple average of the taxpayer’s equity and long term debt capital as of the beginning and end of each calendar year. To calculate an estimate of this tax, PGL and NSG have forecasted their invested capital balances at the beginning and end of 2013, which has the effect of calculating a tax amount that will be recorded as expense and actually paid in 2014. Such a mismatching of test year expenses, including expected 2014 amounts within a 2013 test year is improper and serves to overstate the revenue requirement. To make matters worse, Company witness Ms. Moy then calculates an additional invested capital tax amount at Schedule C-2.14 which she describes as "…necessary in order to recognize the additional Illinois invested capital tax which Peoples Gas will incur due to the proposed increase in operating income. An increase to operating income correspondingly results in an increase to Peoples Gas' retained earnings and thus to its total capitalization, which is the variant factor in the invested capital tax calculation." This further adjustment is wrong for several reasons and should be rejected.

Q. Have you prepared a forecasted Invested Capital tax expense amount that should be included in 2013 test year expense in place of the Company's estimated and then adjusted amount?

A. Yes. Schedule C-11 in AG Exhibits 1.3 and 1.4 sets forth my proposed calculation of test year Invested Capital tax.   For the beginning of the year, the Schedule C-11 calculation employs amounts taken directly from the most recently Invested Capital tax returns filed by the Companies, as provided in response to data requests AG 8.10 and 8.20 for NSG and PGL, respectively. These January 1, 2012 amounts entered into column (B) of Schedule C-11 are then combined with estimated invested capital balances expected to exist at December 31, 2012, as provided in the Companies' response to Staff data requests BAP 5.01 and BAP 5.02. Averaging the beginning and end of year 2012 balances in column D, a 1.0 Illinois apportionment factor and 0.8 percent tax rate are then applied to calculate an estimate of the tax amount that will be accrued on the Companies' books in calendar 2013.

Q. Why are the Companies' proposed invested capital tax amounts, as shown in Line 10 of Schedule C-11, so much higher than the amount you have calculated on Line 9?

A. The Companies' proposed amounts are overstated because the taxes calculated by PGL and NSG are based on estimated investment levels in 2013, and would not be payable or expensed on the books until *after* 2013. In response to data requests AG 8.10 and 8.20 the Companies admitted that "The Illinois Invested Capital tax is recorded on the books as a monthly accrual. The monthly accrual is based upon last year's tax divided by twelve (months)." For this reason, the estimated tax calculation for the 2013 test year should mirror the inputs that will appear on the tax return to be filed by March of 2013, based upon beginning and end-of-year 2012 invested capital balances.

Another reason the Company's proposed test year expenses are overstated is Ms. Moy's proposed Schedule C-2.14 adjustment to include additional tax dollars for an alleged prospective impact from a rate increase in the instant dockets. Her premise that, "An increase to operating income correspondingly results in an increase to Peoples Gas' retained earnings and thus to its total capitalization" is factually correct, but does not accurately predict future Invested Capital taxes in the test year for several reasons:

- It fails to consider any dividends that may be paid out of future retained earnings, which would directly reduce retained earnings and total capitalization.

- It fails to incorporate all other influences upon actual future earnings, such as variations in revenues, expenses, changing interest rates or regulatory disallowances.
- It assumes approval of the Company's proposed level of return on equity and rate base, which amounts are disputed in these dockets.

No adjustment to Invested Capital tax should be made in connection with the rate changes approved in these dockets, for all the reasons just stated, and because rate changes alone cannot be shown to accurately define test year invested capital tax expense levels. A complete and reasonable calculation of test year invested capital taxes is set forth at Schedule C-11 that needs no further adjustment for rate changes or other isolated issues that may impact future earnings and invested capital levels.

Q. Has PGL admitted that its Invested Capital Tax amount proposed for the test year is overstated and should be adjusted downward?

A. Yes. In response to data request AG 10.28, the Company stated, "The 2013 (test year) Invested Capital Tax proposed amount is $12,086,600 (which was adjusted downward to $10,359,000 in our response to BAP 5.01(e))." However, the Company's proposed revised amount of $10,359,000 is still overstated, relative to the calculations in Schedule C-11 because of the use of input information that yields tax estimates that would not be recorded within 2013 for the reasons described earlier. This overstatement is amplified by Ms. Moy's inappropriate rate increase factor-up adjustment that would further increase PGL's proposed tax amount by $356,000.

VIII. SUPPLEMENTAL CHICAGO DOT & CROSS BORES.

Q. What is the purpose of the adjustment you propose at AG Exhibit 1.3, Schedule C-6?

A. This adjustment eliminates the Company's recently proposed $13.9 million increase to test year expenses that was first presented in the Supplemental Direct Testimony of Mr. Kyle Hoops that was filed on October 23. Mr. Hoops claims that these additional expenses not previously reflected in the Company's rate case filing represent, "…known and measureable changes to Peoples Gas' cost of service due to recent changes to the Chicago Department of Transportation ("CDOT") Regulations For Openings, Construction And Repair in the Public Way (new CDOT Regulations) dated July 2012.[26] However, due to a lack of supporting documentation filed by PGL with its Supplemental Direct Testimony in this area and no timely responses to the discovery that was promptly submitted by the AG seeking detailed information regarding this issue, the recently claimed incremental CDOT expenses are being eliminated at this time in Schedule C-6, pending further review and receipt of Company support for these revenue requirement changes.

Q. Were any detailed exhibits or workpapers submitted in support of the asserted CDOT expenses Mr. Hoops would add into the test year revenue requirement?

A. No. A single-page NS-PGL Ex. 20.1 was filed with Mr. Hoops' Supplemental Direct Testimony that provides only a brief "Code Description" of nine lines of breakdown for estimated additional maintenance costs totaling the $13.9 million being sought. No workpapers were filed to state assumptions, indicate calculation

[26] NS-PGL Ex. 20.0, page 1, line 12.

logic, itemize incremental costs or otherwise provide supporting documentation for these new expenses.

Q. **Did the Attorney General submit detailed data requests seeking support for the Company's claimed incremental CDOT expenses?**

A. Yes. Several multi-part questions were submitted in AG data request 10. Responses to these data requests had not been received in time for analysis as this testimony was being finalized.[27] The Company has the burden of justifying such a significant increase in this expense category. To date, that support is lacking.

Q. **Please describe the adjustment appearing at Schedule C-7 of AG Exhibits 1.3 and 1.4.**

A. Another new expense adjustment sponsored by Mr. Hoops in Supplemental Direct Testimony that was filed on October 23 seeks to add $5.7 million per year to PGS O&M expenses and $2.6 million per year to NSG expenses for a new project involving the hiring of contractors to pass cameras through sewer mains and laterals to determine whether a gas line has been "cross-bored" into such facilities, with steps then taken to remedy cross-bores that are found. As in the case of the asserted new CDOT regulation expenses, the lack of any support to date for the Companies' new adjustment justifies the rejection of these incremental expenses in Schedule C-7, pending further review and receipt of Company support for these revenue requirement changes.

Q. **Were any supporting exhibits, workpapers or other documentation provided with the Companies' Supplemental Direct Testimony to support and explain the basis for the asserted incremental, new expenses?**

A. No. Even less information was provided for the Cross-bore project cost estimate than for the CDOT matter. Mr. Hoops' Supplemental Testimony simply states the amounts of additional project expense he has estimated, with no explanation of assumptions, calculation s, logic or underlying supporting documentation.

Q. Did the Attorney General submit detailed data requests seeking support for the Company's claimed incremental CDOT expenses?

A. Yes. Several multi-part questions addressing the cross-bores matter were submitted in AG data request series 10. Responses to these data requests had not been received in time for analysis as this testimony was being finalized.[28] The Company has the burden of justifying such a significant increase in this expense category. To date, that support is lacking.

IX. AFFILIATE O&M EXPENSE ADJUSTMENTS

Q. What is the purpose of the adjustments you have proposed with AG Exhibits 1.3 and 1.4 at Schedule C-8?

A. The Companies provided no detailed supporting calculations for their proposed test year O&M expense forecasts for affiliate charges to PGL and NSG as part of the filed Direct Testimony, Exhibits and Workpapers, so considerable effort was required by the AG to discover and evaluate the basis for such forecasts. With regard to Integrys Business Support, LLC forecasted expenses chargeable to PGL and NSG in the test year, the inquiries made by the AG revealed very large

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[27] Responses to Cross Bores issue data requests AG 10.29 and 10.30 were served electronically by the Companies at 3:42 pm the day before this testimony was due to be filed.

projected IBS cost increases that were not consistent with recent actual spending levels at IBS, and could not be explained by either general wage increase ("GWI") adjustments or by escalation rates applied for inflation. For these unusual projected expense levels that are not consistent with historical actual spending, I propose elimination of the unexplained variances in such costs unless and until the Companies provide in their rebuttal evidence a complete and detailed justification for such projected large expense increases. Quite simply, the Companies failed to meet their burden of explaining and justifying the basis for such large, projected cost increases.

Q. Why are the adjustments you are proposing at Schedule C-8 captioned as "Unexplained Variance" amounts?

A. This was the caption that the Companies used in responding to the referenced AG data requests. These variance amounts are above and beyond the increases caused by proposed escalations within the Companies' forecasts for general wage increases and for general inflation. Only brief and generalized descriptions of anticipated future costs or known causes for expense increases have been proposed for these amounts. More detailed supportive information is required before these forecasted large expense increases from IBS should be allowed into test year expense amounts to be paid by ratepayers.

Q. For the items listed in Schedule C-8, are the projected test year expenses much larger than historically incurred cost levels?

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[28] Responses and objections to data requests AG 10.01, 10.03 through 10.05, 10.32, 10.34, 10.35 and 10.36 were served electronically by the Companies at 3:42 pm the day before this testimony was due to be filed

A. Yes. I have included in AG Exhibit 1.11 copies of the Companies responses to data requests AG 3.06, Attachment 7 and AG 3.14, Attachment 1 which contain this information, as well as the Companies' very limited explanation of, "Key Drivers of 2011-2013 Test Year Increase/(Decrease)" amounts. The IBS line item forecasted expenses I have challenged are those line items in these Attachments with projected test year 2013 expenses (1) that greatly exceed the recorded "Actual" expenses in 2010, 2011 and in 2012, to date; (2) where the "Key Drivers" do not fully justify the "Unexplained Variance" in the response; and (3) where the total projected IBS departmental costs exceed historical cost levels by significant amounts.

Q. The single largest element of your adjustment challenging the Company's IBS forecasted expenses relates to IBS Depreciation on line 9. What explanation have the Companies offered regarding this unexplained variance?

A. The only explanation of "Key Drivers" for this increase is the Company's Work Asset Management System, transaction based software and other net assets. Given the fact that proposed depreciation amounts far exceed the recorded expense levels in 2010, 2011 and 2012, to date, considerably more detailed calculations and explanations should be produced to refine these estimates before they become part of the PGL and NSG revenue requirements.

Q. Does IBS provide services to PGL, NSG and its other affiliates solely at "cost"?

A. No. In addition to assigning or allocating its incurred costs, IBS also charges a return on investment ("ROI") to its affiliates. For the test year, the ROI billings to PGL and NSG are estimated to be $1.8 million and $0.7 million, respectively.[29]

Q. How is the estimated test year return on IBS investment calculated?

[29] PGL Response to data request PGL BAP 16.04, Attachment 1.

A. A pre-tax weighted cost of capital rate is applied to estimates of IBS net book value of assets to derive forecasted ROI amounts.

Q. What is the purpose of the adjustment set forth at AG Exhibits 1.3 and 1.4, Schedule C-9?

A. The pre-tax weighted cost of capital that was used by IBS to formulate test year ROI estimates was based upon the approved amounts in ICC Docket Nos. 09-0166/09-0167 cons. The adjustment I propose would synchronize the ROI with the proposed pretax weighted cost of capital being recommended by the AG, so as to recognize the effects of the refinancing of higher cost debt described later in this testimony, and to reflect the lower return on equity most recently approved by the Commission in Docket Nos. 11-0280/11-0281, Cons.

Q. Has the Company acknowledged the need to update the ROI calculations to reflect more recent ICC-approved capital cost rates?

A. Yes.[30]

X. CASH WORKING CAPITAL.

Q. Have the Companies proposed an allowance for Cash Working Capital ("CWC") within the rate base used to establish the revenue requirement?

A. Yes. NS-PGL Ex. 19.3P and 19.3N set forth the updated lead lag study of CWC that is sponsored by Mr. Hentgen for PGL and NSG, respectively.

Q. Have you incorporated a calculation of CWC within AG Exhibit 1.3 and AG Exhibit 1.4 that recognizes most of the lead and lag day values that are sponsored by Mr. Hentgen in the Companies' lead lag studies?

[30] Id. According to the Company, "An updated test year amount will be included in rebuttal using the pre-tax weighted cost of capital authorized in ICC Docket Nos. 11-0280/11-0281 Cons."

A. Yes. The AG lead lag study calculations are contained at Schedule B-5 of AG Exhibits 1.3 and 1.4. Notably, these calculations do not update the input amounts used to calculate CWC in column B in an effort to: 1) focus attention upon the value of disputed lead lag study issues without introducing other variables into the calculation, and 2) recognizing that the Commission customarily updates CWC calculations using final approved income statement values within the Appendices attached to its Final Orders. Obviously the final, Commission-approved income statement values are not available at this time to calculate a final CWC value for the Companies.

Q. Are there any substantive issues regarding lead/lag values used to calculate CWC?

A. Yes. I have proposed two revisions to the Companies' lead/lag input values, as indicated by shaded cells within AG Schedule B-5. The revisions are to:

- Assign a zero revenue lag day value to Pass Through Taxes, to incorporate the Commission's treatment of this issue in all recent major rate cases, and
- Assign the Other O&M lag day value to Pension and Other Post Employment Benefit ("OPEB") expenses in place of the Companies' assumed zero payment lag value for these expenses.

I do not agree with the Companies' use of arbitrary mid-points within broad 30-day wide ranges of collected receivables balances to estimate the average revenue collection lag, but have not revised the resulting revenue lag values used by the Companies in deference to recent Commission decisions that do not reject or modify the mid-point estimation methodology.

Q. Please explain why you agree with the Commission Final Order in Docket Nos. 11-0280 and 11-0281 regarding the assignment of a zero revenue lag to pass-through taxes.

A. The Companies collect additional charges for pass-through taxes through a Rider tariff. The tariff captioned Rider 1 Additional Charges for Taxes and Customer Charge Adjustments provides for additional charges to customers where NSG and PGL act as collection agents for State and local governments in the collection and remittance of taxes. This process is unique and results in pass-through taxes becoming balance sheet transactions that do not create either gas revenues or tax expenses on the Companies' income statements.[31]

Q. Are pass-through taxes a liability of the Companies that must be paid before taxable revenues have been collected from customers?

A. No. While I am not an attorney and am providing no legal opinion on the matter, my review of laws and regulations that provide for the collection and payment of pass-through taxes by the Companies indicates that such taxes are payable based upon the amounts of collected revenues. For example, the Illinois Gas Use Tax provided for at 35 ILCS 173/5-15 states that, "The tax collected by any delivering supplier shall constitute a debt owed by that person to this State." Similarly, the Municipal Utility Tax provided for at 65 ILCS 5/8-11-2 is a tax on "Gross Receipts" which is defined as, "…the consideration received for distributing, supplying, furnishing or selling gas for use or consumption and not for resale." The Chicago Gas Use Tax at Chapter 3-41-050(6) of the Municipal Code of Chicago provides for Collection of Tax noting that, “The public utility shall not be liable to the city for any tax not actually collected from a retail purchaser.”

Q. How have you modified Schedule B-5 to effect proper treatment of pass-through taxes?

A. I have assigned a zero revenue lag day value to the cash inflows that are associated with the Companies’ collection of pass-through taxes at line 2 of Schedule B-5 in both AG Exhibit 1.3 and AG Exhibit 1.4.

Q. How did Mr. Hentgen treat Pension and OPEB expenses in his calculation of Cash Working Capital?

A. The Companies’ Schedule B-8, at page 1, line 8 assigns a zero expense payment lead value of Pension and OPEB expenses. When the same dollars for collection of revenues associated with these expenses are assigned a full revenue lag at line 1 of Schedule B-8, the resulting CWC requirement included in rate base is significantly increased.

Q. Are Pension and OPEB expenses paid currently in cash each year, such that proper lead lag study treatment of these expenses is easily determined?

A. No. Pension and OPEB expenses are based upon accounting accruals, rather than regular and scheduled payments to vendors like other cash expenses. In responding to Staff data requests on this topic, the Companies noted that, “cash payments do not equal expense accruals recorded for Pension and OPEB.”[32] These responses produced payment information for funding of OPEB amounts indicating several irregularly scheduled contributions made to an insurance plan and a single pension

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[31] See Part 285.315(a) at page 262 showing taxes accrued for State Public Utility, Gross Revenue, Illinois Gas Use, Municipal Utility and Chicago Sales & Use taxes with no corresponding distribution of such taxes to expense account 408, Taxes Other Than Income Tax expense.

funding payment for North Shore but no such funding for PGL in 2011. Without more information and further analysis, it is impossible to discern a reliable payment lead day value from this data. This may be why Mr. Hentgen elected to assign a zero lag day value to Pension and OPEB expenses rather than rely upon an analysis of payment data.

Q. What do you propose as a lead day value for Pension and OPEB expenses, given available information at this time?

A. In my opinion, a reasonable treatment would be to assume the same payment lead day value the Companies have calculated for their payment of the many miscellaneous cash vouchers contained within the Other Operations and Maintenance Expense line of the lead lag study. This lead day value is indicative of how the Companies schedule and pay invoices for the many types of routinely incurred expenses that are not separately studied and listed elsewhere in the lead lag study. Notably, the Other O&M lead day value is much closer to the calculated revenue lag, which dramatically reduces the overstatement of CWC that occurs under the Companies' arbitrary assignment of a zero lead day value.

Q. Is there an alternative treatment for Pension and OPEB expenses that would also be reasonable?

A. Yes. Pension and OPEB expense could be treated like all the other accrual-basis non-cash expenses such as depreciation, amortization and deferred income taxes and removed from lead lag study calculations of income taxes. This would be appropriate for Pension and OPEB expenses because these amounts are actuarially determined and the amount of recorded expense is dependent upon many variables,

[32] PGL/NSG responses to data requests DGK 5.02.

one of which is the amount and timing of contributions that are discretionary on the part of management within ranges bounded by tax and other regulations. To implement this treatment one could either subtract the Pension and OPEB expense amounts from the Line 1 revenues that are assigned a revenue lag or, alternatively, one could set the assumed payment lead for Pension and OPEB expense equal to the revenue lag day value. Either approach would have the effect of eliminating accrual-basis Pension and OPEB expenses from having any impact upon Cash Working Capital.

Q. Have the Companies properly accounting for income tax expenses in the lead lag study of CWC?

A. Yes. The amounts included for Federal Income Tax and State Income Tax in the Companies' Schedule B-8 in column B represent only Currently Payable income tax amounts, properly excluding deferred income taxes that are non-cash expenses that are not being paid to governments. The income tax expense amounts used in the calculation of CWC are pro-forma expense amounts at proposed new revenue levels which will change in the Commission's Final Order in these Dockets.

XI. COST OF CAPITAL

Q. Please explain how Schedule D within AG Exhibits 1.3 and 1.4 was prepared.

A. AG Schedule D summarizes, at lines 1 through 4, the overall cost of capital that is proposed by the Companies in their Supplemental Direct Testimony. Then, at lines 5 through 8 of Schedule D, a comparable overall cost of capital that is being recommended by the AG is presented. The Weighted Earnings Requirements percentages in column E at lines 4 and 8 then carry forward to Schedule A and are multiplied by rate base balances from Schedule B to calculate the required operating income and overall revenue requirement, through the sequence of calculations that appears on Schedule A.

Q. What assumptions were employed in preparing the "AG Proposed" section of Schedule D?

A. The AG proposed capital balances and ratios in columns B and C are the same as the corresponding "Company Proposed" amounts. For the Return on Equity ("ROE"), I inserted the 9.45 percent return that was recently authorized for these utilities by the Commission in Docket Nos. 11-0280/11-0281, consolidated.[33] As discussed below, I have recalculated the cost of Long Term Debt used in the "AG Proposed" section of Schedule D to recognize updated cost rates that should be used for new issuances of long term debt that employ forecasted cost rates in the Company's filing.

Q. What methods and assumptions were used by North Shore Gas to calculate the cost of Long Term Debt for the test year?

A. NSG proposes a cost of Long TermDebt of 4.95%, based upon calculations in the Company's Schedule D-3 that utilize an <u>average</u> accounting method for outstanding monthly debt balances and cost rates throughout 2013. This overall rate assumes a new issuance of bonds planned for May 1, 2013 at an expected cost rate of 4.75 percent.

Q. What methods and assumptions were used by Peoples Gas to calculate the cost of Long Term Debt for the test year?

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[33] <u>Final Order</u> Docket Nos. 11-0280 cons. dated January 10, 2012, page 141

A. PGL proposes a cost of Long TermDebt of 4.58 percent, based upon calculations in the Company's Schedule D-3 that utilize an average accounting method for outstanding monthly debt balances and cost rates throughout 2013.. This overall rate also assumes two new issuances of bonds planned for November 2012 at an expected cost rate of 4.05 percent and for September of 2013 at an expected cost rate of 4.95 percent.

Q. Is the Companies' approach to estimation of the cost of Long Term Debt reasonable?

A. No. The Companies' use of an average monthly accounting method for outstanding bonds is grossly inconsistent with the Companies' advocacy for use of a year-end rate base. Using a year-end rate base is objectionable for the reasons noted earlier in my testimony. To compound the overstatement of their respective proposed revenu e requirements, North Shore and PGL clearly expect to refinance older higher cost bonds at currently lower market interest rates during the 2013 test year, but have elected to use an average Long Term Debt cost rate calculation approach that is inconsistent with their year-end rate base and that would deny ratepayers full participation in the annual interest savings resulting from such refinancing activity.

Another problem with the Companies' calculation of Long Term Debt cost is the overstatement of expected interest coupon rates for each of the forecasted new issuances. The Company's estimated cost rates were based upon projected yields for 10-year treasuries in the relevant future periods, plus an estimated risk premium for each utility, as more fully explained in the responses to data requests AG 8.01 and AG 8.11. Copies of these responses and related exhibits are included in AG Exhibit 1.12.

Q. Is there more current information that should be used to estimate cost rates for newly issued bonds of NSG and PGL?

A. Yes. According to the Companies' SEC 10Q Report for the period ended September 30, 2012, "In October 2012, PGL secured commitments for $100 million of 30-year 3.98% Series YY First and Refunding Mortgage Bonds with a delayed draw feature. These bonds will be issued in December 2012." To re-calculate PGL's average test year cost of Long Term Debt, I have replaced the late 2012 bond issuance for which PGL estimated a term of 10-years and a cost of 4.05 percent with the actual 3.98 percent cost rate and longer term that is now known to exist for this issuance. For the second refinancing planned for September 2013, I also utilized the same 3.98 percent cost rate, but left the term of that assumed issuance at PGL's assumed 10-year period. The result of these changes to new issuance costs under the Company's average monthly accounting approach reduces the test year overall cost of Long Term Debt from PGL's proposed 4.58 percent level to 4.46 percent. If a year-end costing approach is used, PGL's annualized cost of debt at December 2013 would be further revised to 4.20 percent to fully capture the savings from re-financing.

. For North Shore, I modified the Company's assumed cost rate of 4.75 percent for planned new issuance of bonds in May 2013 using the most recent known cost rate of 3.98 percent that was actually incurred for PGL's recent issuance, as described above. This changed assumption , using the Company's average monthly accounting approach reduces the test year overall cost of Long Term Debt from NSG's proposed 4.95 percent level to 4.60 percent. If a year-end costing approach is used, NSG's annualized cost of debt at December 2013 would be further revised to 4.22 percent to fully capture the savings from re-financing.

Q. Why is it reasonable to assume no increase in the cost of long term debt during 2013, relative to the cost rates experienced by PGL in its recently placed bonds?

A. The Federal Reserve has publicly announced its intent to maintain a highly accomodative monetary policy through at least mid-2015 and announced on October 24, 2012 its intent to continue to put downward pressure on longer-term interest rates.[34] There is no basis to support the assumed significant increases in Long Term Debt yields that the Companies have included in their projected cost calculations.

Q. Have you included within AG Exhibits 1.3 and 1.4 the revised monthly average cost rates for Long Term Debt, including re-priced new issuance costs, rather than your lower year-end annualized cost rates, to determine test year revenue requirements?

A. The AG Exhibits include the revised costs for Long Term Debt produced under the Company's selected average method because the AG is advocating use of an average rate base. If the Commission ultimately agrees with the Companies that a year-end rate base should be employed, the significantly lower year-end cost of Long Term Debt described in my testimony should be used. Such a "matching" of investment levels and capital cost rates at test year-end is essential, but has not been accomplished in the Companies' asserted revenue requirement.

[34] See Federal Reserve press release dated 10/24/12, available at: http://www.federalreserve.gov/newsevents/press/monetary/20121024a.htm

Q. Have you independently quantified an appropriate return on equity ("ROE") for the Companies?

A. No. The 9.45 percent ROE found reasonable by the Commission earlier this year for PGL and NSG is consistent with the recent ROE findings for gas distribution utilities that I have observed in other state commission rate orders.[35]

XII. CONCLUSION AND RECOMMENDATION.

Q. What is your recommendation regarding the initial revenue requirement to be determined for Peoples Gas Light and Coke Company?

A. I recommend that PGL's revenue requirement be found to be no larger than the amount shown in AG Exhibit 1.3, at Schedule A, column D, line 7. This amount should be further modified for any Commission-approved ratemaking adjustments proposed by the Staff and other parties, that are not addressed in my or Mr. Effron's Direct Testimony.

Q. What is your recommendation regarding the initial revenue requirement to be determined for North Shore Gas Company?

A. I recommend that PGL's revenue requirement be found to be *no larger than* the amount shown in AG Exhibit 1.4, at Schedule A, column D, line 7. This amount should be further modified for any Commission-approved ratemaking adjustments proposed by the Staff and other parties, that are not addressed in my or Mr. Effron's Direct Testimony.

[35] The November 2012 Public Utilities Fortnightly 2012 Rate Case Study indicates gas utility authorized ROE levels ranged from 9.06% authorized by the Illinois Commission for Ameren to a high of 10.7% included in a settlement involving Atmos energy in Georgia. Most of the authorized ROE levels for gas utilities were within 30 basis points of the 9.45% level most recently approved for PGL and NSG.

Q. **Do AG Exhibits 1.3 and 1.4 also include the impact of adjustments being proposed by Mr. Effron?**

A. Yes. An index appearing at page one of each Exhibit lists the Schedules contained therein and indicates the sponsoring witness for each adjustment, including each of the individual adjustments to rate base and operating income that are being supported by Mr. Effron.

Q. **Does this conclude your testimony at this time?**

A. Yes.